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Centralized and decentralized electrolysis-based hydrogen supply systems for road transportation – A modeling study of current and future costs

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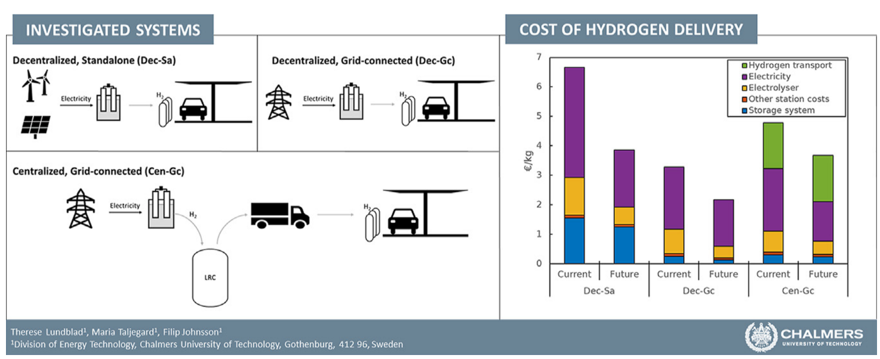
HIGHLIGHTS

- Three electrolysis-based hydrogen supply systems are compared.
- Comparisons are made between centralized/decentralized systems.
- Both grid-connected and stand-alone systems are evaluated.
- For most regions, decentralized grid-connected systems have the lowest costs.

GRAPHICAL ABSTRACT



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ABSTRACT

This work compares the costs of three electrolysis-based hydrogen supply systems for heavy road transportation: a decentralized, off-grid system for hydrogen production from wind and solar power (Dec-Sa); a decentralized system connected to the electricity grid (Dec-Gc); and a centralized grid-connected electrolyzer with hydrogen transported to refueling stations (Cen-Gc). A cost-minimizing optimization model was developed in which the hydrogen production is designed to meet the demand at refueling stations at the lowest total cost for two timeframes: one with current electricity prices and one with estimated future prices. The results show that: For most of the studied geographical regions, Dec-Gc gives the lowest costs of hydrogen delivery (2.2–3.3€/kgH_2), while Dec-Sa entails higher hydrogen production costs (2.5–6.7€/kgH_2). In addition, the centralized system (Cen-Gc) involves lower costs for production and storage than the grid-connected decentralized system (Dec-Gc), although the additional costs for hydrogen transport increase the total cost (3.5–4.8€/kgH_2).

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Introduction

To meet the European climate targets, reducing the levels of emissions linked to transportation represents a key challenge, given that the transportation sector accounts for 37% of global greenhouse gas (GHG) emissions and about 25% of European GHG emissions (excluding international maritime emissions) [1–3]. Hydrogen has been identified as a potential energy carrier in the transition to a sustainable transport sector, especially with respect to heavy freight transport [4–6]. Although hydrogen is hardly used for transportation at present, it is employed extensively in industry. Hydrogen can be produced from a variety of sources, with steam methane reforming (SMR) of natural gas currently accounting for the largest share of production, followed by oil reforming and coal gasification. These processes are associated with significant GHG emissions. However, when it comes to hydrogen use in the energy transition, water electrolysis and SMR of natural gas or biogas with carbon capture and storage (CCS) are of greatest interest [7–9].

The supplying of hydrogen to refueling stations has been evaluated in several studies [10–21]. Hydrogen production can be located at the site of the refueling station, i.e., in a decentralized system, or can be centrally located in combination with a distribution system that transports hydrogen from the production site to the refueling station [13]. An overview of the current trend in installations of hydrogen refueling stations was performed by Samsun et al. [20]. They found the number of hydrogen refueling stations to be growing, although they also concluded that an increase in the rate of installations is needed in order to meet target numbers in the coming years. For hydrogen that is produced through electrolysis, the production cost is heavily dependent upon the cost of electricity [21], and the estimates of the levelized cost of hydrogen (LCOH) available in the literature are based on historical electricity price data. A future electricity system with high shares of variable renewable electricity (VRE) production could generate more severe fluctuations in electricity prices, thereby altering the conditions for hydrogen production. Tang et al. [11] compared hydrogen production at refueling stations in Sweden that are run in island mode (i.e., not connected to the electric grid) using dedicated wind and solar power units with a similar albeit grid-connected system, and they concluded that grid connection tends to achieve a lower LCOH. However, since Tang et al. [11] assumed a constant hydrogen demand using historical spot market prices for the electricity supplied to the electrolyzer, these prices may not be representative of a future electricity system with a higher share of VRE.

An economic analysis of a standalone wind-powered system for supplying hydrogen to refueling stations in Sweden was conducted by Siyal et al. [10]. They concluded that such a setup could help towards reaching the goal of a fossil-free transport sector in Sweden, although the setup investigated was not compared with other systems for hydrogen production. Göcek and Kale [15] used a techno-economic analysis to assess the feasibility of a hydrogen refueling station powered by either a wind-photovoltaics (PV)-battery or wind-battery system located on the island of Gökçeada, Turkey. They found that such systems could be feasible for the chosen site and that a hybrid wind-PV-battery system yielded a lower LCOH than did a wind-battery system [15]. Janssen et al. [12] studied off-grid hydrogen production in different European countries. They concluded that electrolyzer systems that supply electricity using both wind power and solar PV to power an electrolyzer gave the lowest costs for nearly all countries studied. They further concluded that with projected cost reductions, off-grid hydrogen production from renewable sources could yield a cost similar to that of conventional hydrogen production [12]. That study was not targeting the transport sector, and hydrogen compression and storage were not included. Furthermore, the study did not consider hydrogen production systems connected to an electric grid with renewable electricity. Nistor et al. [17] performed a techno-economic study of a hydrogen refueling station in the UK, focusing on the short-to medium-term representation of technology and costs, comparing a wind-powered system run in island mode with a similar grid-connected system. For the grid-powered system, a fixed electricity price was used. They found that the grid-connected and standalone wind-powered systems had a similar LCOH; however, the grid-connected system had a larger share of the cost as operational costs, while the island-mode system had a larger investment cost. They expressed a need for further investigation of the tradeoffs between installed wind power capacity and hydrogen storage size [17].

Ulleberg and Hancke [18] studied hydrogen production in a Norwegian context using two small-scale production cases that employ water electrolysis. In the first case, local hydropower was used to power an electrolyzer at the site, while the second case looked at a hydrogen refueling station, comparing on-site hydrogen production with a centralized supply system. They achieved lower costs for hydrogen production in the second case, due to a large extent to increased utilization [18]. In that study, optimization was not performed and no estimations were made of how their defined cases would be affected by changes in the electricity system composition and any consequent changes in electricity prices.

The station configuration and operation of hydrogen refueling stations have also been the subjects of previous studies. In 2020, Riedl [22] presented a hydrogen station design tool that can predict the performance and operating costs of a refueling station and that has been validated using real-life data from refueling stations (albeit without optimization of the configuration). Reddi et al. [23] compared the configuration and operational strategies of compression and storage systems at hydrogen refueling stations. They found that large cost reductions could be achieved through optimizing the storage and compression regimes [23]. The energy demand for the operation of a refueling station (thus, excluding hydrogen production) was studied by Rothuizen and Rokni [24]. They found that compression was responsible for the largest share (approximately 50%) of the operational energy demand at the refueling station, followed by the cooling of hydrogen after compression (approximately 30% of the energy demand).

Although the abovementioned studies have provided valuable insights into the cost of hydrogen production for the transport sector, studies that evaluate multiple hydrogen supply systems are lacking. For situations with more than one supply system, the studies are limited to modeling their costs using historical electricity price profiles. This paper examines the cost of three electrolysis-based hydrogen production systems that supply hydrogen to refueling stations for heavy transport. The goals are to identify the differences between centralized and decentralized hydrogen production systems, as well as the differences between standalone and grid-connected systems for supplying hydrogen to refueling stations. Both the current and a possible future electricity system are considered, to evaluate how the cost efficiencies of the different hydrogen supply systems change as the electricity system evolves.

Method

The present study develops and applies a techno-economic optimization model to compare the system efficiency and cost of hydrogen delivery for the three hydrogen supply systems, including the electricity source, energy conversion to hydrogen, and the distribution and storage of hydrogen. For the three hydrogen supply systems investigated, the energy demand and related costs for the different parts of the supply system are used to estimate the system costs. Optimization is carried out to satisfy an exogenous hydrogen demand profile at the lowest total cost. Although the methodology can be applied to any region, Sweden and the electricity price area SE3 is chosen as the main case. In addition to this, three regions, Ireland, Croatio-Slovenia-Hungary, and western Spain, are modeled to determine how costs are influenced by different electricity system compositions, as well as by different potentials for wind and solar power.

Hydrogen supply systems

As indicated above, the hydrogen that is used at refueling stations can either be produced where it is consumed or produced centrally and distributed from the production site to the refueling station. The hydrogen supply systems investigated in this work are concerned with hydrogen that is produced from water electrolysis. At the refueling station, the hydrogen is contained in a storage system, and following transfer to a dispenser it is used to fill the onboard tanks of vehicles.

The three hydrogen supply systems investigated are as follows:

(1) **Decentralized-Standalone (Dec-Sa).** In this system, hydrogen is produced at the refueling station, with a standalone system using dedicated wind power plants and/or solar PV that are located in the vicinity of the refueling station and provide the electricity for the electrolyzer. Hydrogen storage tanks are used to store the hydrogen between production and demand at the refueling station.

(2) **Decentralized-Grid-connected (Dec-Gc).** This is similar to the Dec-Sa system but uses electricity supplied from the local electricity grid to power the electrolyzer. Current and possible future electricity price scenarios are used.

(3) **Centralized-Grid-connected (Cen-Gc).** This is a large-scale, centralized hydrogen production system using electrolysis, from which the hydrogen is distributed to several refueling stations via trucks. Large-scale, lined rock cavern (LRC) centralized storage is used to smoothen the seasonal variations, while a storage system similar to that used in the decentralized systems (Dec-Sa and Dec-Gc) is used to store the hydrogen at a higher pressure at the refueling station. Current and possible future electricity price scenarios are used.

Fig. 1 shows a visualization of the modeled hydrogen supply systems. For the decentralized hydrogen supply systems (Dec-Sa and Dec-Gc), hydrogen production is located at the same site as the refueling station, while production is separated from the refueling station for the centralized supply system (Cen-Gc). Hydrogen can be stored in a variety of forms, such as liquid hydrogen, compressed gas, and metal hydrides, as well as in cryogenic storage. Compressed gas storage is the most commonly used strategy for refueling station applications. If the hydrogen is stored at high pressure, cooling is needed to maintain the integrity of the storage vessel [25]. All the cases use tube storage as the storage option at refueling stations. Compression to a refueling pressure of 700 bar and cooling are included in the model. For the Cen-Gc system, the model can choose to invest in LRC storage at the production site.

Model

The individual components of the hydrogen supply system are dimensioned for each system using a cost-minimizing linear optimization model run in GAMS (using a Cplex solver) that ensures that the level of production matches the hydrogen demand at the refueling station at the lowest total cost. The model has an hourly temporal resolution and is run for one full year. For the Dec-Sa system, the model optimizes investments in wind power, solar power, the electrolyzer, and storage system capacities, so as to identify the setup with the lowest cost that can satisfy the demand at all hours of the year. For the Dec-Gc system, the model optimizes investments in the electrolyzer and storage capacity, as well as those hours during which the system operates, and consequently, defining when electricity is purchased. The Cen-Gc system has the same variables as the Dec-Gc system, albeit with the added option of investment in centralized, large-scale storage capacity at the production site. Transport of hydrogen is assumed to occur continuously in the Cen-Gc system.

Equation (1) describes the objective function of the model. For the decentralized hydrogen supply systems (Dec-Sa and Dec-Gc), there are no transport costs. Equation (2) expresses an energy balance for hydrogen storage technologies. For tube storage at the refueling station, the hourly discharge of the hydrogen storage ($s^{rem}_{pst,t}$) is equal to the

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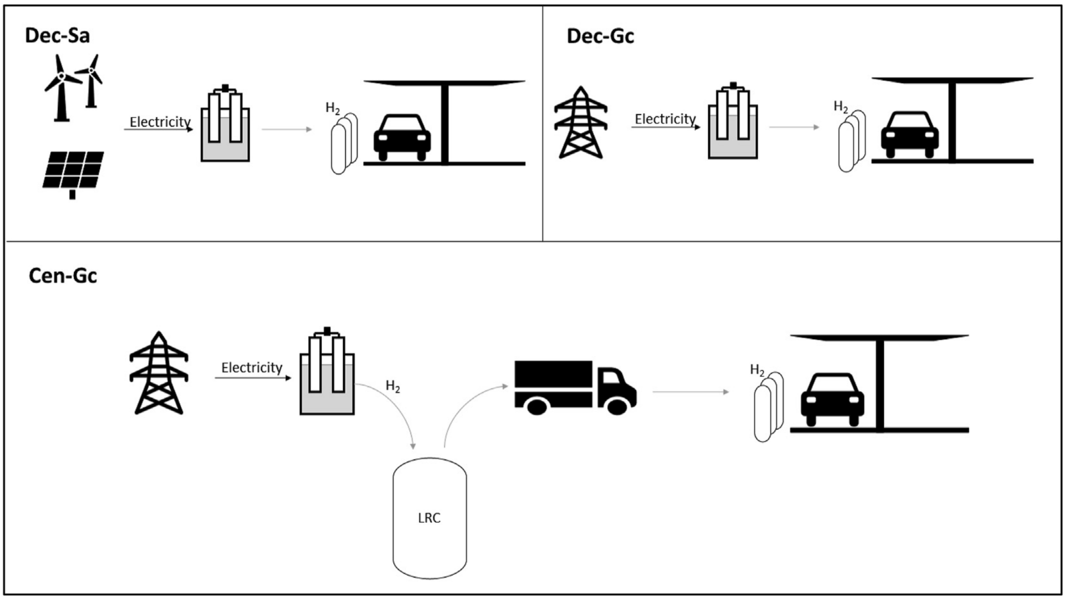

Fig. 1 – Visualization of the hydrogen supply systems investigated in this work. For the Dec-Sa and Dec-Gc systems, hydrogen production occurs on-site, while the Cen-Gc system requires transport of hydrogen.

hourly hydrogen demand. In the Cen-Gc system, the hydrogen supplied to the tube storage is equal to the hydrogen discharged earlier from the LRC storage at the centralized production site. The experienced delay in delivery reflects the assumed distance between the production site and the refueling station. Equation (3) describes the relationship between the hydrogen supplied to the storage at the production site and the electricity used for hydrogen production. For the Cen-Gc system, the hydrogen produced through electrolysis is equal to the hydrogen supplied to the hydrogen storage at the production site. Equations (4) and (5) describe limitations as to how much hydrogen can be stored and the possible rates of charging for the different hydrogen storage technologies. Equation (6) describes the relationship between the total electricity demand and the electricity demand of the different technologies. The electricity demand from compression and cooling is directly related to the produced amount of hydrogen. Equation (7) defines which variables are positive. The total system costs are divided by the total hydrogen demand in each hydrogen supply system to obtain the LCOH. Descriptions of the notations used in the equations are listed in Table 1.

$$s^{add}_{pst,t} \le W_{pst} * i_{pst} \tag{5}$$

$$k^{el}_{tot,t} = k^{el}_{ely,t} + k^{el}_{comp,t} + k^{el}_{cool,t} \tag{6}$$

$$0 \le g_{p,t};\, i_p;\, k^{el}_{p,t};\, l_{pst,t};\, s^{add}_{pst,t};\, s^{rem}_{pst,t} \tag{7}$$

Costs and assumptions

In the modeling, costs and technological assumptions are chosen to reflect both the current and future state of hydrogen supply systems. Table 2 lists the input data to the model. While taxes and government-mandated fees are excluded from the cost estimations, so are subsidies and other forms of financial support. Costs related to the construction and operation of the refueling station that are not specified in the table are not included in this study. A current or future estimation is used when available, such that the future estimation may be regarded as an interpretation of Year 2050. The wind and solar power production profiles are taken from Mattsson et al. [26] and represent the average hourly production levels in the regions investigated. The wind power profile represents the production levels of conventional wind power plants at locations in the modeled regions with average wind speeds in the range of 7–8 m/s. The model does not have any limitations regarding the smallest storage or production capacity in which it must invest, as long as the demand can be met for all hours.

$$\min \left[C^{tot} = \sum\nolimits_p \left(C_p * i_p \right) + C^{el,fix} + \sum\nolimits_t \left(k^{el}_{tot,t} * C^{el,var}_t \right) + C_{station} + C^{fix}_{transp} + d * C^{var}_{transp} \right] \tag{1}$$

$$l_{pst,t++1} = l_{pst,t} + s^{add}_{pst,t} - s^{rem}_{pst,t} \tag{2}$$

$$\sum\nolimits_{pst} s^{add}_{pst,t} = k^{el}_{ely,t} * \eta_{ely} \tag{3}$$

$$l_{pst,t} \le i_{pst} \tag{4}$$

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Table 1 – The sets and abbreviations (lower-case letters), parameters (upper-case letters), and variables (italic lower-case letters) for Equations (1)–(6).

Notation	Description
t	Set of modeled timesteps
p	Set of modeled technologies
pst	A subset of p, hydrogen storage technologies
η_{ely}	The combined efficiency of the electrolyzer
C_p	Annualized cost for technology p
$C^{el,fix}$	Annual fixed electricity cost
$C_t^{el,var}$	Varying cost of electricity in timestep t
C^{tot}	Total annual system cost for one refueling station
$C_{station}$	Other station costs
C_{transp}^{fix}	Fixed transport cost
C_{transp}^{var}	Varying transport cost
comp	Compression
cool	Cooling
d	Distance from production site to refueling station
ely	Electrolyzer
$g_{p,t}$	Generation from technology p in timestep t
i_p	Capacity of technology p
$k_{p,t}^{el}$	Electricity use for technology p in timestep t
$l_{pst,t}$	Hydrogen level in storage pst in timestep t
$s_{pst,t}^{add}$	Hydrogen added to hydrogen storage pst in timestep t
$s_{pst,t}^{rem}$	Hydrogen removed from hydrogen storage pst in timestep t
W_{pst}	The maximum injection rate of storage pst

The hydrogen demand profile is shown in Fig. 2. It spans one year with hourly resolution, and is obtained from authentic hourly driving data for heavy transport [36,37]. In this study, it is assumed that the refueling station studied does not affect the current electricity price curve. However, for the future estimations, the considered electricity price curve is for a system that includes hydrogen usage by both the industry and transport sectors. Electricity price area SE3 in Sweden is chosen as the main case for this study, and the current and future electricity price curves used in the modeling are shown in Fig. 3. Electricity spot prices from Nord Pool for Year 2019 are used for the current cases [38], and an electricity price curve for future cases for all the studied regions is extracted from a modeling study conducted by Walter et al. [39]. The future electricity prices are the marginal electricity prices derived from an optimization model of the European electricity system (called eNODE) that has zero direct GHG emissions, i.e., a system that can be seen to envision the Year 2050 system [39]. A scenario described by Walter et al. [36] that includes a hydrogen demand of 1000 TWh per year in the industry and transport sectors in Europe is used. The electricity price curve from this model contains prices that fluctuate to a much greater degree than current prices as seen in Fig. 3, owing to a larger share of VRE and more hours with higher and lower prices. The hydrogen optimization model developed in the present study is run for both current and future investment and electricity costs for all the hydrogen supply systems.

Sensitivity analysis

As stated above, electricity prices account for a large fraction of the production costs when electrolysis is used to produce hydrogen. Therefore, the optimization model was run with different historical electricity price profiles from Nord Pool SE3 (for 2015–2020), to examine how the electricity cost could vary under current conditions and how that could affect the system setup. Fig. 4 shows the sorted historical electricity prices used.

For the Cen-Gc system, the costs associated with transport between the production site and the refueling station are dependent upon the assumed distance. Therefore, the average distance ranged from 50 km to 500 km in the current case. This affected the time needed for hydrogen delivery, as well as the cost for transport, both of which were scaled linearly (although the time needed for delivery was rounded up to the nearest hour).

In the linear optimization model, some costs are scalable, while other costs are assumed to be fixed. This means that assumptions made regarding the refueling station size can affect the results. The non-scalable costs used in the model are related to the construction of the refueling station (see *Refueling station* in Table 2). The annual demand was varied to investigate how the costs that are not linearly scalable influence the results. The refueling station size was varied for delivering an average output of 150–2000 kgH_2/day, equivalent to approximately 5–67 full truck tanks per day. Setting an average output with a given demand profile that varies between hours means that the maximum production capacity over a year is larger than this. In addition to varying the daily average output, the Dec-Gc system was modeled with a fixed hourly demand that was the same for all hours throughout the years, so as to assess the impact of the assumed demand profile.

As the linear optimization model will always give the most cost-efficient solution, the size of the electrolyzer was varied to change the full-load hours of the electrolyzer, to evaluate how the results are influenced. This was carried out for the Dec-Gc system using the current case in Sweden.

Results

Fig. 5 shows the LCOH for the investigated hydrogen supply systems when assuming current and future costs. The electricity costs shown in Fig. 5 include the costs for electricity used for hydrogen production and compression. The results show that the lowest costs for delivering hydrogen in Southern Sweden, 2.2–3.3€/kgH_2, are achieved with the decentralized grid-conneceted system (Dec-Gc). For the centralized hydrogen supply system, Cen-Gc, somewhat lower costs are achieved for the production and storage of hydrogen, although the additional cost for hydrogen transport makes the total cost, 3.7–4.8€/kgH_2, 31% higher for the current case and

Table 2 – Input data for the technical and economic assumptions made. The numbers in bold differ between the time-frames. The future estimation could be interpreted as a representation of Year 2050.

Component	Characteristic	Current estimation	Future estimation	Unit	Reference
Grid-connected electricity	Power tariff	31.5	31.5	k€/MW and year	[27]
	Fixed annual cost	1819	1819	€/year	[27]
Wind power	Investment cost	**1120**	**960**	k€/MW	[28]
	Annual fixed O&M cost	**14.00**	**11.34**	k€/MW	[28]
	Annual variable O&M cost	**1.5**	**1.22**	€/MWh	[28]
Solar power	Investment cost	**560**	**290**	k€/MW	[28]
	Annual fixed O&M cost	**11.3**	**7.4**	k€/MW	[28]
Electrolyzer	Efficiency	**65**	**74**	%	[29]
	Investment cost	**900**	**500**	k€/MW	[29]
	Annual O&M cost	4	4	% of investment cost	[29]
	Water consumption	10	10	liters/kgH_2	[29]
	Purified water cost	1	1	€/m3	[30]
Transportation[1]	Starting cost	0.42	0.42	€/kgH_2	[31]
	Truck transport	0.0076	0.0076	€/kgH_2 and km	[31]
	Average time of transport	3	3	hours	
Tube storage and compressor	Input capacity	10	10	% of max capacity/h	
	Investment cost (including compressor)	**57**	**22**	k€/MWh	[25]
	Annual O&M cost (including compressor)	**6**	**4**	M€/MWh	[25]
	Electricity demand for compressor	12	12	% of hydrogen energy content	[32]
	Electricity demand for cooling	7.2	7.2	% of hydrogen energy content	[24]
Large-scale storage (LRC)	Investment cost	11	11	k€/MWh	[33]
Refueling station	Water system investment cost	7.8	7.8	k€	[34]
	Water system annual O&M cost	3	3	% of investment cost	[34]
	Dispenser system investment cost	**65**	**44**	k€/dispenser	[35]
	Dispenser system annual O&M cost	3	3	% of investment cost	[35]
	Relation between daily hydrogen demand and number of dispensers	250	250	kgH_2/dispenser and day	[23]
	Average amount of hydrogen supplied	450	450	kgH_2/day	
Economic assumptions	System lifetime	25	25	years	
	Discount rate	5	5	%	

O&M, operational and maintenance.

41% higher for the future case, as compared with the Dec-Gc system.

The Dec-Sa system, which is disconnected from the electric grid, is associated with the highest LCOH, mainly due to the higher costs for storage and electricity production, as shown in Fig. 5.

For all the tested systems, lower costs are achieved in future cases than in the case corresponding to present conditions, as seen in Fig. 5. For the Dec-Sa system, this is mostly due to the assumed lowering of investment costs, as well as to the assumptions made regarding increased energy efficiency of the used technologies. For the grid-connected systems, this is also the main contributor to cost reductions, although the electricity price variations also affect during which hours hydrogen is produced and, thereby, the electricity costs.

Fig. 6 shows the full-load hours for the electrolyzers in each hydrogen supply system, in terms of both current and future costs. The number of full-load hours varies between 4000 and 7300 hours depending on the hydrogen supply system and timeframe. The future timeframe for the decentralized hydrogen supply systems, Dec-Sa and Dec-Gc, show a slight increase in the electrolyzers' full-load hours, indicating that hydrogen is produced at a more even rate throughout the year. For the Cen-Gc system, a decrease is seen in the number of full-load hours for the electrolyzers, indicating that the decrease in investment costs for electrolyzers makes it cost-efficient to increase the hourly hydrogen production capacity through investing in additional electrolyzers, thereby giving a lower utilization rate.

For the Dec-Sa system, which is not connected to the electricity grid, electricity availability is dependent upon variations in wind speed and solar radiation. This results in hydrogen production that varies more between hours, as compared with the grid-connected systems, Dec-Gc and Cen-GC. A larger investment in electrolyzer capacity is needed to enable sufficiently high overproduction during hours when electricity is available, in order to cover the hydrogen demand during periods of lower availability. This results in fewer full-load hours for this system, assuming both current and future costs (Fig. 6). For the grid-connected supply systems, Dec-Gc and Cen-Gc, electricity can always be purchased; however, with the availability of storage, the most-

[1] The fixed and variable costs for compressed gas trucks was interpolated from Ref. [31] based on the lower estimate for transport need.

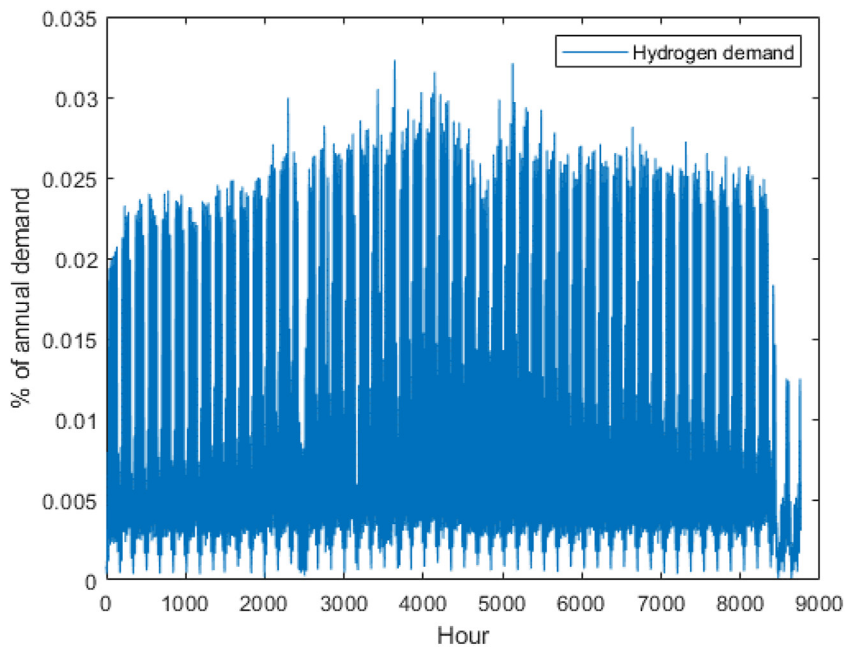

Fig. 2 – Hydrogen demand profile derived from driving data for heavy transport.

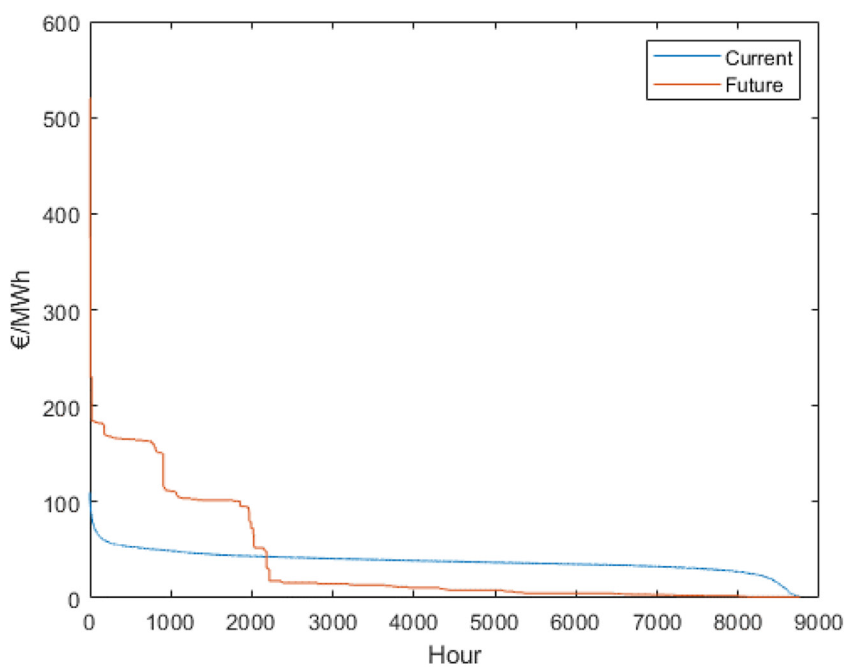

Fig. 3 – Sorted electricity prices for electricity price area SE3. Data for Year 2019 collected from Nord Pool are used for the current estimation [38]. The data for a future estimation (representing a Year 2050 system with net-zero direct GHG emissions) are taken from Walter et al. [39].

expensive hours can be avoided. In addition, the level of production can be lowered independently of the electricity cost when the demand is low and the level of hydrogen in storage is sufficient. The increase in electrolyzer capacity for the Cen-Gc system between the two timeframes indicates that it is cost-efficient to increase the production capacity as electricity price fluctuations increase, but only if there is an option for investing in LRC storage. This can be concluded as there is no corresponding increase in electrolyzer capacity in the Dec-Gc system.

The levels of hydrogen in storage for every hour of a year and for each of the studied hydrogen supply systems are shown in Fig. 7. The storage levels for the centralized system, Cen-Gc, are scaled so they represent the demand allocated to a refueling station of the same size as for the decentralized hydrogen supply systems. The highest value in the graph for

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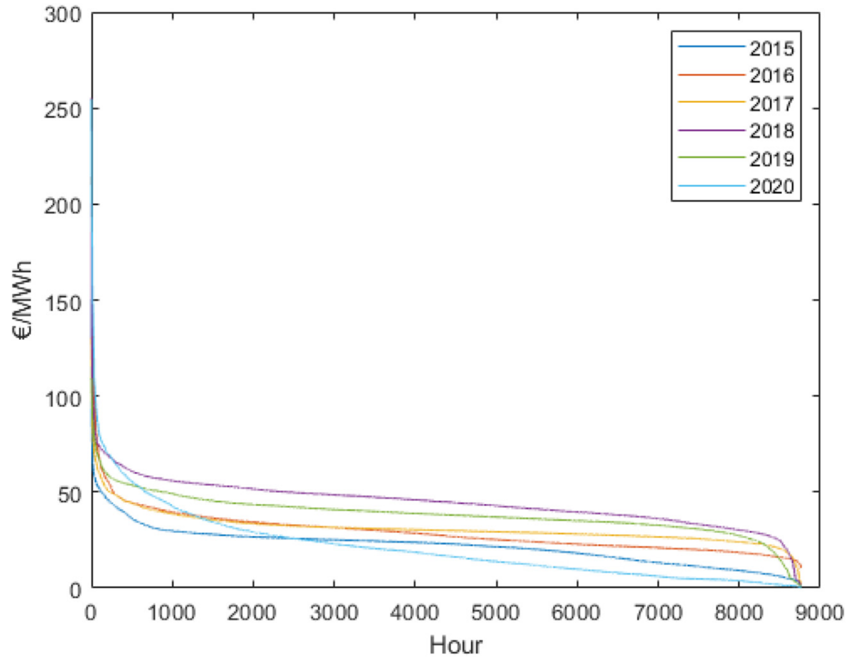

Fig. 4 – Sorted electricity prices for electricity price area SE3 and for each of the years in the period 2015–2020 [38].

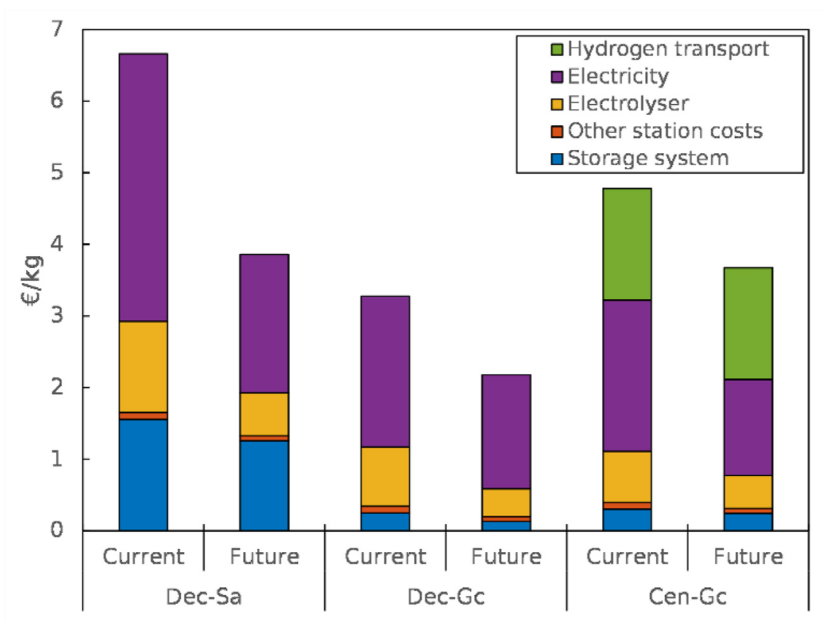

Fig. 5 – Levelized cost of hydrogen delivery for the three hydrogen supply systems and the two timeframes investigated.

each system is the selected size of the storage. As can be seen from Fig. 7, the system that is not connected to the electricity grid, Dec-Sa, has the largest storage capacity per refueling station, while the lowest capacity is selected by the model for the decentralized, grid-connected system, Dec-Gc. Periods of the year with low levels of wind and solar power production increase the storage demand in the Dec-Sa system, thereby lowering the storage utilization level compared to the other supply systems. As the wind power production and hydrogen demand profiles do not follow each other, there will be hours of the year during which the marginal cost of hydrogen will be close to zero, as well as other hours that are dimensioning for the system, giving a high marginal cost of hydrogen during those hours.

For the two grid-connected hydrogen supply systems studied, Dec-Gc and Cen-Gc, hydrogen is generally produced close-in-time to consumption, as is evident from Fig. 7. Investments in storage for the Dec-Gc system are small, and are sized to allow for the rate of compression, rather than for storage between hours. For the Cen-Gc system, the demand is

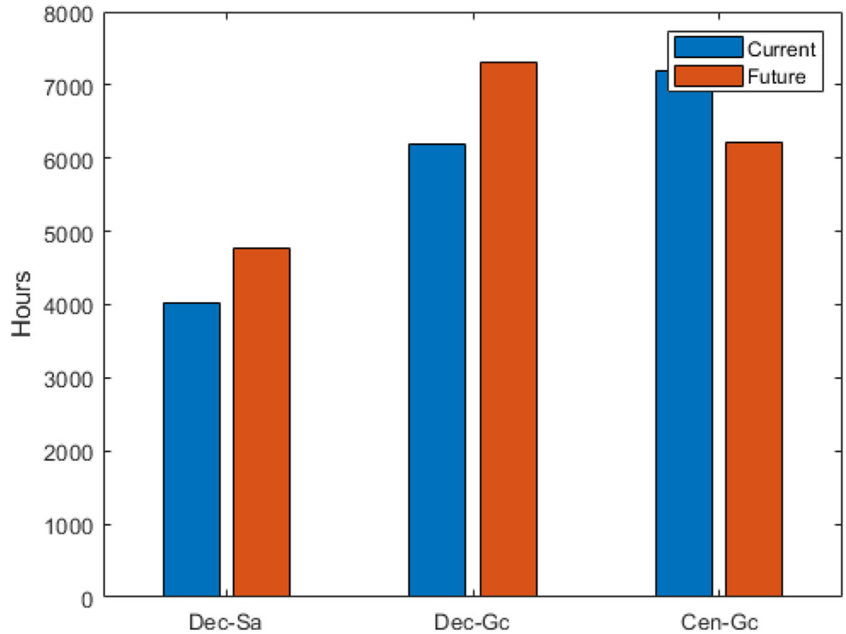

Fig. 6 – Full-load hours for the electrolyzer used in each of the hydrogen supply systems for the two timeframes investigated.

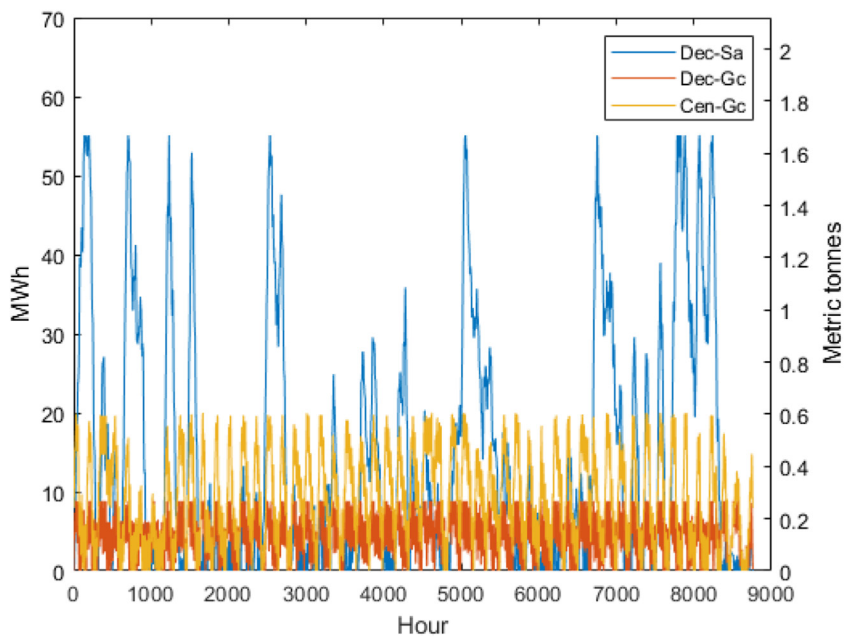

Fig. 7 – Levels of stored hydrogen for the studied hydrogen supply systems on an hourly timescale. The centralized supply system, Cen-Gc, is scaled to represent the same total annual hydrogen demand as the other two systems.

scaled downwards to represent the demand at a single refueling station of the same size as for the other supply systems. For the Cen-Gc system, the displayed value is the sum of hydrogen levels in the centralized LRC storage and the storage unit at the refueling station.

Fig. 8 shows how local conditions (comparing southern Sweden with western Spain, Ireland, and Croatia-Slovenia-Hungary) influence the optimal setups and cost-efficiencies of the different hydrogen supply systems. The results for all three hydrogen supply systems are shown for the future case. The lowest total cost is between 2.2 and 2.5 €/kgH_2 for all regions except Croatia-Slovenia-Hungary, where the lowest total cost is 3.2 €/kgH_2. However, the hydrogen supply system with the lowest cost differ between the countries as seen in Fig. 8. It is clear from Fig. 8 that for hydrogen supply systems, the location of the system affects the setup, and thereby the costs of hydrogen production. Unlike for the other regions, the lowest cost for a Dec-Sa system is achieved

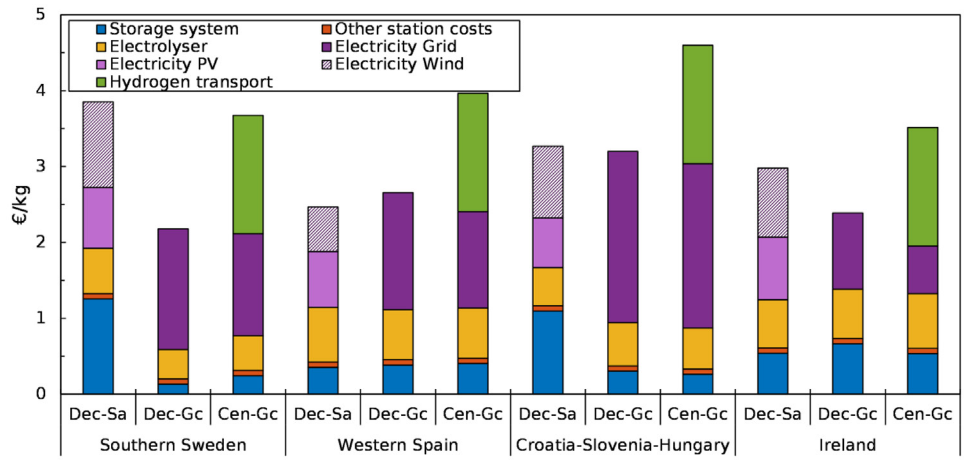

Fig. 8 – Levelized cost of hydrogen delivery for the different regions and supply systems, for the proposed future timeframe.

in western Spain, where the solar potential is much greater than in the other regions. That this region has the lowest LCOH for the Dec-Sa system may be attributable to the demand peaking during daytime, which means that it follows to some extent the solar power production profile. In addition, there are no fees for power transmission in the Dec-Sa case. For Ireland, a country with high wind power outputs, the costs for the Dec-Sa system are the second-lowest. The highest costs for such a system are seen for southern Sweden, an area with a lower potential for solar power, and the second-highest costs are observed in Croatia-Slovenia-Hungary. Despite the varying potentials for solar and wind power, a mix of these two energy sources is more cost-effective than using only one technology for electricity supply in all the regions. For the Dec-Gc systems, the costs are lowest in Sweden, followed by Ireland and western Spain. Comparing the Dec-Gc system with the Cen-Gc system, the greatest difference is seen for Ireland. Here, the electricity costs drop substantially when the option of large-scale storage is introduced. Even in Ireland, the introduced cost for distribution makes this system more expensive than a decentralized system. With the given assumptions, this would be true even if the average transport distance would be lowered to only a few kilometers.

Sensitivity analysis

Fig. 9 presents the results of the sensitivity analysis in which the average distance from the hydrogen production site to the refueling stations in the Cen-Gc system ranges from 50 km to

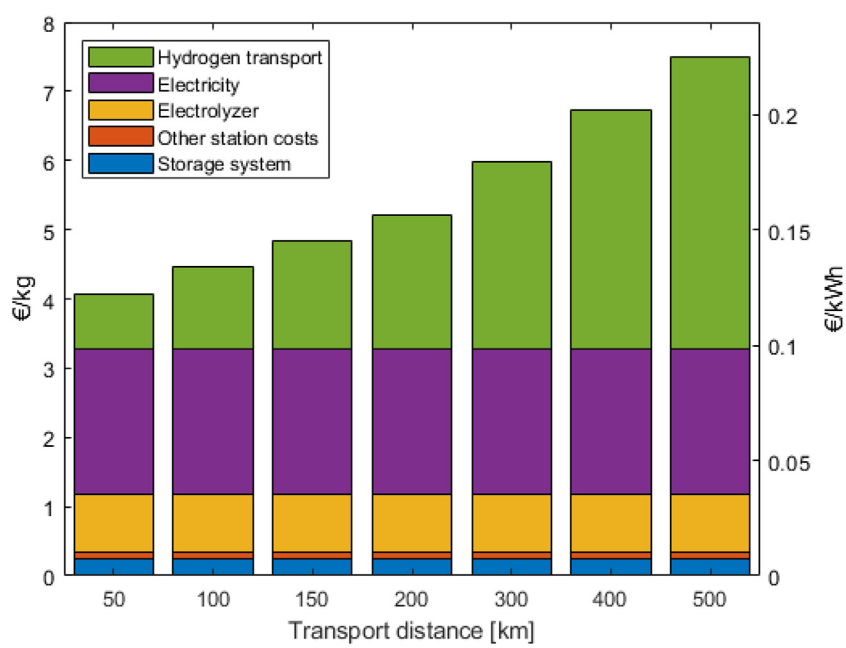

Fig. 9 – Costs for hydrogen from the Centralized, grid-connected system (Cen-Gc) and the current timeframe applying different average hydrogen transport distances from the production site to the refueling station.

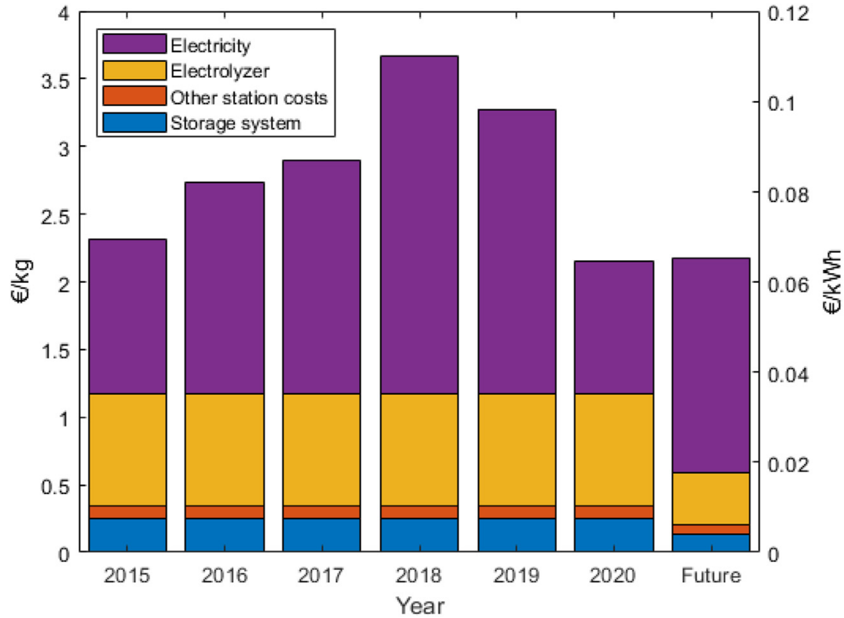

Fig. 10 – Results for the Decentralized, grid-connected system (Dec-Gc) using electricity price curves from Nord Pool for each year in the period 2015–2020 [23], as well as the future estimation. Note that scale on vertical axis is different from Fig. 9.

500 km. For all the distances, the costs of centralized production remain higher than the costs for decentralized hydrogen production shown in Fig. 5.

Fig. 10 gives the results for the Dec-Gc system using different electricity price profiles from Nord Pool SE3 (for each of the years in the period 2015–2020) and for the future price profile assumed in the present work. The results show that the model invests in the same capacities for storage and electrolyzers for all the systems, with the exception of the future estimation, for which the assumed technical efficiencies and cost data differ from those of the systems using the current technology. While the different electricity price curves (i.e., for the years of 2015–2020) for grid-connected hydrogen supply systems exert impacts on the LCOH, they do not affect the system setup. From this it can be concluded that the current electricity price variations are not severe enough to motivate further investments in storage capacity.

As the assumed refueling station size affects costs that are not scaled linearly, the model was run with three different average demands from the refueling stations. The results are

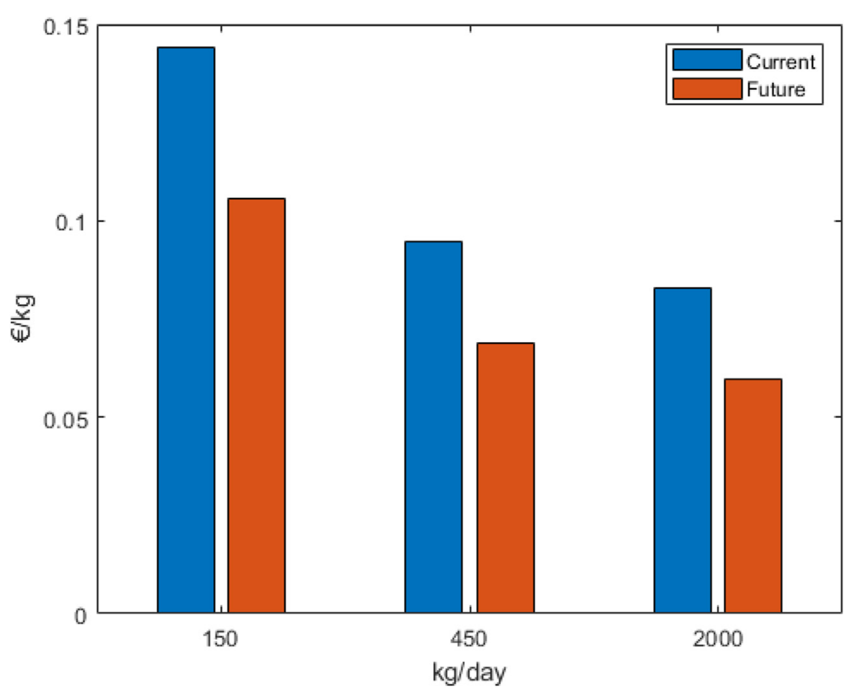

Fig. 11 – Other station costs per kg of H_2 for different average daily demand levels.

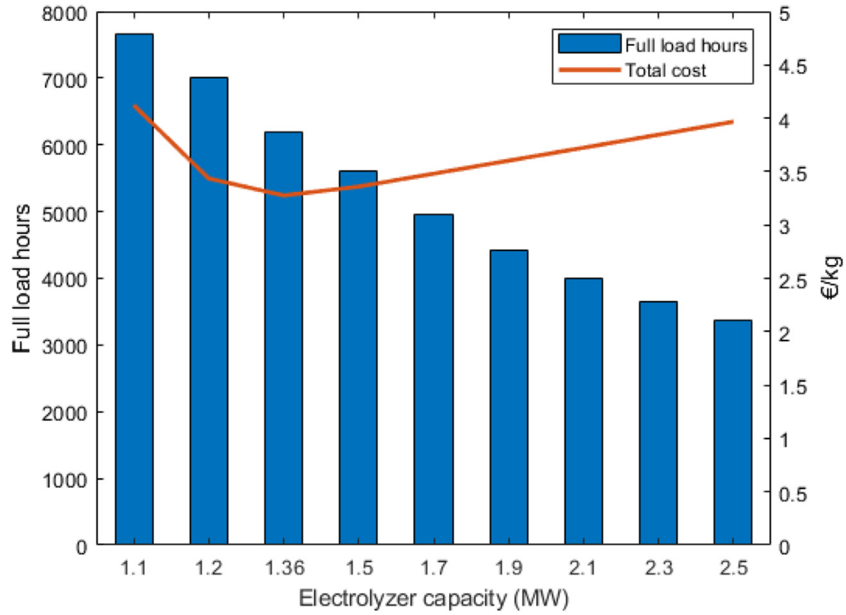

Fig. 12 – Full-load hours for the electrolyzer (left y-axis) and total cost of hydrogen delivery (right y-axis) when varying the size of the electrolyzer for Sweden and the Decentralized, grid-connected system.

shown in Fig. 11. The costs that are not scaled linearly are listed under *Refueling station* in Table 2, and shown as *Other station costs* in previous results. A slight decrease in refueling station costs per delivered kg of hydrogen is observed when increasing the station size. However, compared with the total costs of hydrogen delivery, the station costs correspond to 1.4%–3.2% of the LCOH for the different supply systems and timeframes for Sweden. This indicates that the economic barrier to adding a refueling station at an existing location for hydrogen production is low. When running the model with a fixed demand for all hours during the year, 6% lower costs are achieved for current systems, while 4% higher system costs are achieved for future systems. These differences are much smaller than the uncertainties related to the results.

The cost variations for the Dec-Gc system operated under current conditions when varying the size of the electrolyzer are shown in Fig. 12. The lowest total cost is achieved with an electrolyzer capacity of 1.36 MW for the station delivering an average of 450 kg of hydrogen per day. Near-perfect solutions give small variations in the LCOH delivered. Even with large investments in electrolyzer capacity, the effect on LCOH is limited as seen in Fig. 12.

Discussion

The presented results represent optimized solutions with perfect foresight. It is, therefore, likely that real-world refueling stations would need larger storage systems than those presented in this study, as there must be some element of flexibility to a cost-optimal solution. In addition to this, the hydrogen will be sold at a price that ensures a profit margin. The real price of hydrogen delivery will, to a large extent, depend on the extent of utilization of the station, meaning that the market penetration level affects the profitability of introducing hydrogen refueling stations. Furthermore, the storage sizes suggested by the optimization model reflect the lowest storage sizes needed without regard to the security of supply in a system that has perfect foresight and no redundancy. Thus, real-world conditions will increase the costs of the hydrogen supply systems, and these increases may differ between the different hydrogen supply systems.

Currently, degradation of the electrolyzer is not included in the model. This means that the current estimation of electrolyzer capacity is an optimal solution in a world in which the capacity remains constant throughout the lifecycle. For a case in which the capacity of the electrolyzer decreases over time, a larger initial investment would be needed to ensure sufficient capacity towards the end of its lifetime; alternatively, there should be earlier reinvestment. This means that the electrolyzer costs would likely be higher in a real-world case.

The wind and solar data used to model the Dec-Sa system are representative of the average power production levels in electricity price area SE3. This gives a slightly smoother power output than when using wind or solar data for a specific location. However, it also makes the approximation more generalized. Losses and outages for planned and unplanned maintenance work are included in the profile estimations. However, a single unit, such as that in the Dec-Sa system, is obviously more-sensitive to stops. This is not captured in the model, and a larger storage unit might be needed to manage unplanned stops to electricity production. Furthermore, only conventional wind power plants are included in the model. Possible improvements would be to allow for investments in wind power plant types that are optimized for low wind speeds, and to include an assumed development of wind power plants for the future case.

One could argue that allowing the distribution of hydrogen through pipelines would lower the transport cost, thereby making centralized solutions more cost-efficient. However, the observed differences in production and storage costs between the grid-connected hydrogen supply systems, Dec-Gc and Cen-Gc, are small, and it seems unlikely that centralized systems will be ramped up in parallel with the possible development of increased hydrogen demand for heavy transport. Since the present work does not include any other sectors, it is not possible to speculate regarding the effects that other sectors would have on driving the development of hydrogen infrastructure. In a case where hydrogen is developed within other sectors, such as in industry, it might be more economically beneficial for the transport sector to be connected to centralized supply systems.

The number of full-load hours for electrolyzers is high, despite the option of large-scale storage in the Cen-Gc system. Furthermore, the investments in LRC storage are small, despite the technology being cheaper than the tube storage used for the decentralized systems. The combination of many full-load hours and low-level investments in storage capacity reveals that hydrogen is produced at a rate close to its demand throughout the year. These results indicate that it will not be cost-efficient to invest in large-scale storage solely in response to the demands from the transport sector in Sweden. This is the case even though the costs of LRC used in the model may be underestimated due to the costs being scaled linearly and the invested capacity being smaller than the storage capacity of units upon which the costs are based. However, if production and storage were to be coupled with other sectors, the transport sector might also utilize such storage if incentivized by other sectors. It is also possible that the marginal cost of increasing storage capacity for storage constructed by another sector is low enough to motivate a centralized hydrogen supply system, such as Cen-Gc, so as to meet the needs of the transport sector.

The model optimization in this work is designed to minimize the total system cost, which does not necessarily provide the optimal system configurations, as there may be important design factors other than costs. For example, an advantage of the Dec-Sa system that is not valued in the model is its self-sufficiency and independence from technical changes in the other parts of the electricity system. Another potential advantage of such a system is the possibility to establish refueling stations in areas where grid capacity cannot accommodate a grid-connected solution, or where grid development is more costly than assumed in this study. A centralized system, such as the Cen-Gc system, could also be an option in areas with limitations on grid capacity, since for a production site in a centralized system, especially one with distribution through hydrogen pipelines, there is more freedom with regards to the placement of the hydrogen production site. This means that refueling stations could be placed in areas with poor grid availability and still have access to clean hydrogen, as long as the station is connected to the system of hydrogen pipelines.

The present work investigates hydrogen supply systems using exogenously given electricity prices, which means that the studied refueling station/s do not affect the electricity price curve. However, as stated above, the price profile for the future case includes a hydrogen demand for both the transport and industry sectors. The share of market penetration for hydrogen as a transport fuel could influence the electricity price profiles, which is a topic that should be explored further. As the transport sector is currently not using hydrogen extensively, the assumption that the introduction of hydrogen refueling stations would not have a major impact on current electricity prices seems appropriate. However, regional electricity grids could have limitations on grid capacity that could in turn impose limitations on grid-connected hydrogen production for both the current and future timeframes. These would be interesting to evaluate further, to identify those limitations that are the most important to consider and to assess how hydrogen production could be an asset rather than a burden for the regional electricity grid.

When constructing a refueling station, some costs are scalable, while others will be fixed, independent of the size of the station, as presented in the sensitivity analysis. However, as the model was run with different sizes of hydrogen refueling stations, no significant differences in LCOH were observed, as the station costs that are not scalable make up a very small share of the costs of hydrogen production. For a centralized production case, refueling station size could affect the demand for storage, as the size of the demand at the refueling station would affect the number of trucks needed for delivery. This aspect is not captured by the linear optimization model.

The LCOH is directly dependent upon the rate of utilization of the refueling station. As the sensitivity analysis showed that the demand pattern had only a weak influence on the cost-optimal system setup, future refueling patterns could be an area of interest. In a system with a low market penetration of hydrogen-powered vehicles, the predictability of hydrogen demand could suffer from wide margins of error, which would strongly affect the costs for hydrogen delivery. Further work is needed to elucidate the parts of the heavy transport sector that are most likely to undergo a transition to running on hydrogen. This would provide further insights into the geographic distribution of hydrogen demand, as well as hydrogen refueling patterns.

As there are uncertainties regarding the cost of the hydrogen supply, this study should be regarded as an evaluation of the differences between different types of hydrogen supply systems, rather than as an estimation of hydrogen supply costs in absolute terms. In addition, the estimations for the future case should not be seen as predictions but instead as a comparison between today's electricity system and future systems with more volatile electricity prices.

Conclusions

Three hydrogen supply systems were evaluated using a cost optimization model, to gain insights into the cost of supplying hydrogen to the transport sector. The costs of hydrogen delivery were in the range of 2.2–6.7 €/kgH_2 in Sweden. The lowest cost for hydrogen delivery was achieved with the decentralized grid-connected supply system (Dec-Gc). The difference between the two decentralized systems (Dec-Sa and Dec-Gc) is exemplified by the finding that decentralized grid-connected systems have a 44%–51% lower cost for hydrogen delivery than decentralized standalone systems in Sweden under the given assumptions. The grid-connected system had a lower LCOH for all regions, except for western Spain, where the standalone system (Dec-Sa) had the lowest LCOH. If a standalone system were to be introduced, it would be more cost-efficient to combine solar and wind power, rather than only supplying electricity using one of the two technologies. This is true for all the studied regions, although the cost-optimal shares of wind and solar power differ slightly between the regions.

From the comparison of decentralized and centralized grid-connected hydrogen supply systems (Cen-Gc and Dec-Gc), it can be concluded that, given the assumptions presented in this paper, a centralized production system (Cen-Gc) is 31%–41% more expensive than a decentralized grid-connected system (Dec-Gc) in Sweden. The Cen-Gc system was more expensive than the Dec-Gc system in all the studied regions. Although slightly lower costs for hydrogen production and storage were achieved in the Cen-Gc system, the additional cost for hydrogen transport to the refueling station resulted in a higher total cost. Thus, the higher cost for hydrogen transport offsets the advantage of having access to large-scale hydrogen storage. If there is an existing system for hydrogen transport (such as an existing system of hydrogen pipelines) for other purposes, it might be more cost-effective to use that system. For the centralized system (Cen-Gc), an increase in electricity price variations between hours strengthens the business case for investments in larger and cheaper hydrogen storage solutions, which can enable shifts in hydrogen production to periods with low electricity prices.

For future cases, the hydrogen production costs are between 23 and 42% lower than when assuming today's prices for the different hydrogen supply systems when looking at Swedish conditions. This is due to a combination of assumptions related to decreased investment costs (e.g., investment costs for electrolyzers) and lower costs for purchased electricity.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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